

**NOVA SCOTIA ELECTRICITY MARKETPLACE GOVERNANCE
COMMITTEE**

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**ENSURING ADEQUATE GENERATION AND
TRANSMISSION INVESTMENT**

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1 INTRODUCTION

Ensuring adequate levels of investment in new generation and transmission system facilities is a key concern in jurisdictions with restructured electric power markets. Inadequate generation supply was one of the critical factors contributing to energy price spikes in California and Alberta. Transmission bottlenecks such as California's Path 15 can also be very costly to consumers. This is an issue that is given considerable attention in the U.S. Federal Energy Regulatory Commission's recently issued Notice of Proposed Rulemaking on Standard Market Design.

Under the traditional regulated monopoly model, the vertically integrated utility had the responsibility to forecast load growth, future fuel prices, and the need for investment in new generation and transmission system resources. Under this model, generation and transmission planning were closely linked. In restructured electricity markets, however, generation and transmission are increasingly separated. Furthermore, absent a more formal market structure for ensuring capacity, price signals and investors seeking above market returns will be the fundamental market forces that ensure adequate generating capacity. This deintegration of the electric power system planning and investment decision-making process necessitates new arrangements for ensuring generation adequacy and needed transmission system expansion. This Issues Paper is a guide to these arrangements.

The *Energy Strategy* has already laid out the broad parameters of the framework for new generation investments in Nova Scotia assuming that the existing market structure is maintained. Specifically, it stated that

[t]he government will . . . allow competition for the construction of any future electrical generation. The UARB will determine when new capacity is required and call for bids from NSPI and any other producers. NSPI will continue to have an obligation to serve Nova Scotians.¹

This framework is analogous to the arrangement in Québec, where independent power producers can participate in competitive solicitations for supply alongside the generation division of Hydro-Québec. In Québec, however, responsibility for evaluating the need for new capacity resides with the distribution division of Hydro-Québec.

This framework for ensuring generation adequacy in Nova Scotia is predicated on NSPI having a continued obligation to serve all but its

¹ Province of Nova Scotia, *Nova Scotia's Energy Strategy*, 2001, Volume 1, p. 26.

wholesale customers, as indicated in the *Energy Strategy*. Wholesale customers — currently six municipal utilities — together account for only about two percent of load. With a continued NSPI obligation to serve about 98 percent of the market, current arrangements governing adequacy of supply will remain mostly unchanged, except that there will be competition among suppliers to provide the capacity required by NSPI's customers. However, the Committee has expressed an interest in considering alternative market models that would reflect a broader scope for competition in the Province. Under these models, when retail competition is allowed, it becomes increasingly difficult for NSPI to maintain an obligation to serve. Thus, there is a need to evaluate alternative mechanisms that can be used to ensure that generation adequacy would be assured under different market structures. If there is not an obligation on customers to take supply from a specific entity, then it is inappropriate for that entity to have an obligation to supply the customers. Under such a framework, the supplier has an obligation to incur costs to serve the customer, but has no offsetting obligation on the part of the customers to pay for the costs incurred by the supplier. Such a structure is not sustainable and exposes the supplier to considerable risk.

The issues with respect to transmission system investment can be summarized with three questions. Who should evaluate the need for new transmission investments? How is the need for new transmission investments evaluated? Who makes the necessary investments? To the degree that these issues are not addressed by the transmission system owner, alternative mechanisms will likely be required for building transmission infrastructure.

2 GENERATION ADEQUACY

Restructuring jurisdictions have pursued a range of different alternatives for ensuring adequate generation investment. Some allow the market to decide when to build new capacity, with high prices acting as a signal for generation project developers.² Others require sufficient capacity to meet anticipated peak load plus reserves to be contracted by any load-serving entity (*i.e.*, retailer or other party with an obligation to serve retail customers).³ Some establish responsibilities for the system operator to buy capacity centrally through long-term bid solicitations whenever required to ensure that certain reliability targets are met.⁴ Yet others mandate that government-owned entities build generation when the market does not itself add enough new generation to reliably meet load. In New York, for example, the New York Power Authority has taken the role of adding peaking generation in areas where the market has not added sufficient reserves to reliably serve load. In Florida, a similar structure is being contemplated, whereby the Florida Public Service Commission would have the authority to require regulated utilities to add capacity whenever the market adds too little to reliably serve load. Considerable care needs to be taken when introducing non-market mechanisms to support generation investment in jurisdictions that have decided to rely on markets.

² This is the approach that is utilized by Alberta where there is only an energy market and no obligation on any party to provide capacity. Under this market structure, price signals in the energy market administered by the Power Pool of Alberta (Power Pool) are assumed to provide a sufficient price signal for developers to build adequate capacity.

³ This approach is generally used in New England, New York and PJM. See Section 2.2.

⁴ A system operator is the entity with the responsibility to monitor and control the electric system in real time.

2.1 Alternatives to Installed Reserve Requirement

The Committee will need to evaluate whether there is a continued need for an installed reserve requirement and if so who should be responsible for establishing and monitoring this requirement. The calculation of an installed reserve requirement (or the amount of installed reserves needed) seeks to ensure that sufficient generation has been constructed so that when multiple generators are either on a scheduled or forced outage there is a high probability of being able to meet the load without interruption. The target loss of load expectation that system planners uses for generation adequacy is of 1 day of generation adequacy attributed outages in ten years. If a 20% reserve requirement were needed, a peak load of 2,000 MW (after accounting for on site generation and demand reduction when needed) would require 2,000 MW of generation plus an installed reserve requirement of 400 MW (based on the 20% reserve requirement.)

Historically, reliability of generation in the Province has been assured by NSPI. As part of its resource planning process, NSPI forecasts future peak loads and determines the reserve requirement. These two factors establish the amount of capacity required to reliably serve customer requirements.

If the Committee decides to recommend a more broad-based market scope where NSPI would not have the obligation to serve, other structures for ensuring generation adequacy need to be considered. One alternative is to rely on an energy market that allows extreme price excursions during hours of relative energy shortage. In theory these high energy prices (and ancillary service prices), even if paid infrequently, provide those building capacity with sufficient revenues to pay their capital costs even if their units sell only infrequently into these markets. These systems can result in high price volatility and a boom and bust cycle of new generation additions if project developers do a poor job of anticipating market capacity requirements and the development plans of competitors.

The premise of an energy-only type structure is that there is a central market with clearing prices, and that every generator is paid the market-clearing price. There is some question as to how an energy-only type system would be applied within a bilateral-only type market structure. The theory would be the same for a bilateral contract market; bilateral contract prices rise as the market gets short of capacity. However, a major challenge with applying this model to the bilateral contract model is the lack of market price visibility for project developers. Indeed, one of the favourable attributes of bilateral contracts based markets is that they avoid the price volatility of bid-based pools. The lack of price transparency suggests that bilateral markets are likely to need an installed reserve requirement. The price signal provided by these markets is not likely to provide sufficient advance warning to develop needed

capacity in time to avoid generation shortages that will imperil reliability of supply.

Another alternative would be to use a balancing charge to support the loss of generation supporting a bilateral transaction. Under this proposal, when generation supporting a transaction is not available but still required, a balancing charge could be levied based on offers to provide this service. But it would be difficult to ensure that the payments made to generation for this service would be sufficient to cover capital costs needed to keep surplus capacity on the system, especially if the payments were made only a few hours during a few years of the life of the facility. Furthermore, the balancing charge might ultimately reflect the type of pricing dynamics that are reflected in an energy-only market. In sum, there appear to be no viable market structures that would allow a reliable bilateral-only system, without an installed reserve requirement.

If the Committee decides there is a continued need for an installed reserve requirement as appears appropriate, it will need to consider who should be responsible for establishing and monitoring this requirement. Whether this responsibility is given to the regulator or system operator,⁵ there will be a need to evaluate the need for future generation additions. This will require forecasting of demand and available system resources. At a minimum, this responsibility will be taken on by the regional reliability council, which is charged with a mandate to perform such an evaluation. Typically, the data required by these regional reliability councils are provided by their members, *i.e.*, the electric utilities of which the region is composed. However, there are limitations with the material provided by regional reliability councils. Specifically, the focus is on short-term resource adequacy assessment. The regional reliability councils do not make a direct evaluation of a region's need for additional generating capacity.

In Ontario, the Independent Market Operator (IMO) has responsibility for both short-term and long-term adequacy assessments. Its *18-Month Outlook* and *10-Year Outlook* present a peak demand forecast and identify existing and committed generation and transmission resources. Based on this information, the IMO indicates whether the available generation is adequate to satisfy the target reliability objective. The IMO also presents a high demand forecast scenario and evaluates whether potential new generation projects which are known but have not been included in the generation assessment are likely to be able to address this potential capacity shortfall. The IMO also assesses the

⁵ Remember that this market structure presumes that the incumbent electric utility no longer has an obligation to serve and is just one supplier in the market. Therefore, it is no longer appropriate to have it responsible for performing this function.

capability of the transmission system and evaluates the potential for transmission congestion under a range of different operating conditions.

The information reported by the IMO goes well beyond the information that would be available through the regional reliability council. Furthermore, this information is valuable to market participants and provides a good starting point for independent assessments regarding the adequacy of Ontario's generation resources that are performed by and on behalf of generation project developers. Access to independent and authoritative information on projected demand and supply would be a key component of a more broadly-based competitive market in Nova Scotia.

2.2 Responsibility for Acquiring Installed Reserves

The next choice facing the Committee if it decides to continue with an installed reserve requirement is who should be responsible for acquiring resources to satisfy that requirement. There are several alternative approaches to addressing this issue, including:

- Requiring anyone serving load (*i.e.*, load-serving entities or LSEs) or generators selling to LSEs to acquire installed reserves;
- Having the system operator acquire these reserves and provide them as an ancillary service to all loads;
- Having some regulated entity such as the provider of Standard Offer Service provide installed reserves.

The three northeastern system operators — PJM, NY-ISO, and ISO-NE — all impose minimum reserve margin requirements on LSEs. The installed capacity obligations require LSEs to contract for installed capacity (ICAP) sufficient to cover peak load and an established reserve requirement. Installed capability is generally measured through a capability audit where the maximum claimed capability of the generator is established through a test that is prescribed by the system operator. A contract for ICAP provides the holder with no rights for energy at a specific price. However, if a supplier is providing ICAP there generally is a requirement to provide energy when requested by the system operator under emergency conditions.

ICAP markets may be appropriate for securing new generating facilities and for maintaining existing generating facilities that operate for only limited periods or not at all. If a generator is totally dependent on selling power to cover both fixed and variable costs, the generator will build a new plant only if the generator is reasonably certain that the new plant will sell enough power to recover both variable and fixed costs, including a profit sufficient to induce the generator to build the plant.

An advantage of this approach, at least if the ICAP requirement is imposed far enough in advance and strictly enforced with high enough penalties, is that it can essentially guarantee that a specified amount of installed capacity will be in place in advance. But there are disadvantages to such a system in a competitive market, most of them related to the fact that the system operator or some other party would have to make many detailed decisions that are commercially critical to market participants. The system operator must determine each individual LSE's ICAP obligation based on the projected or past loads of its customers. It must decide the amount of ICAP each generating unit can sell, based on its type, historical performance, recent upgrades and location relative to transmission constraints. And it must impose a system of tests and penalties to enforce these rules. There are other criticisms of ICAP obligations. One criticism is that ICAP payments goes to the existing generators and does not necessarily lead others to enter the market to increase capacity. Depending on how the ICAP rules are designed, existing generators may be able to exercise market power, forcing up ICAP prices. In some markets, trading has been so thin at times that there is a question about whether the market price is competitive. In some cases, the ISO has intervened to set the price administratively, and market participants have expressed concern that the price does not accurately reflect the forward value of generating capacity. Some power generators see short-term ICAP payments as providing inadequate assurance of capital cost recovery to motivate new investment. Finally, many parties object that ICAP focuses on power generation, ignoring the potential of demand response.

The Standard Market Design proposed by the U.S. Federal Energy Regulatory Commission (FERC) includes a long-term resource adequacy requirement that would replace current ICAP programs.⁶ The proposed arrangement would require each LSE to shoulder its share of future regional needs. This could be achieved through self-supply, contracts to purchase generation, biddable demand or other demand-response programs. An Independent Transmission Provider (*e.g.*, RTO) would be responsible for forecasting demand for its area, facilitating the determination of an adequate level of regional resources by a regional state advisory committee, and assigning each LSE in its area a share of the needed future resources. In the case of a power shortage, the Independent Transmission Provider (ITP) would add a per-megawatt-hour penalty during the shortage to the price of energy taken from the spot market by a LSE that did not meet its share of the regional needs for that year. If operating reserves decrease to the point that the ITP must curtail load, LSEs that failed to meet their generation resource

⁶FERC, *Notice of Proposed Rulemaking: Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Docket No. RM01-12-000, July 31, 2002, pp. 252-90, at <http://www.ferc.gov/Electric/RTO/Mrkt-Strct-comments/nopr/RM01-12-000toc.pdf>.

adequacy requirement are subject to the first curtailment to the degree that this is feasible.

One alternative arrangement is to assign the task of acquiring installed reserves to the system operator. For this alternative the system operator acquires installed reserves under a long-term competitive solicitation and provides these to all customers at cost as an ancillary service. If desired, these competitive solicitations could be made to reflect non-price factors or societal goals if agreement could be reached as to the appropriate balance of price and non-price considerations. To avoid redundancy, installed reserve service could be a must-take ancillary service. The regulated SOS supplier could bid to make generation resources available to the system operator for this service but would only be selected if it was the low cost supplier and if the resources that it was offering are in fact surplus to its commitments.

For the alternative where both those providing SOS and non-SOS service must acquire installed reserves, care should still be taken to avoid creating incentives to install redundant reserves or else costs are likely to increase for the SOS or non-SOS provider. For this alternative exit fees should be designed so that departing customers would pay exit fees that covered the difference between the market price of reserves and the regulated cost of these reserves. Those that hold installed reserves that had been purchased during the regulated era on behalf of departing customers should be allowed to price those at market prices. Where market prices are below regulated costs, the above market portion of the cost should be collected in the exit fees charged to departing customers to avoid increasing costs to SOS customers.

A problem of additional costs for redundant reserves would exist if the system operator were to be required to acquire installed capacity to provide for reliability, but where loads are given an option of buying this service from the system operator or some other source. The burden of paying for the service would fall on those taking the service, even if resources must be acquired and available for those not taking the service. Thus if the system operator must acquire resources to meet reserve requirements, it can increase costs if customers are allowed to shop for these services.

Finally, reserves could be held as regulated assets of the regulated SOS provider. All load would be responsible for a proportional share of this cost-based rate.

4 TRANSMISSION PLANNING AND EXPANSION

Currently, NSPI is responsible for transmission planning and expansion. In the future, the transmission of electricity will continue to be a monopoly service by NSPI. To meet FERC's reciprocity requirements, however, NSPI will be required to separate accounting for its generation, transmission, and distribution divisions. Major questions to be decided regarding transmission planning and expansion include:

- Who should evaluate the need for transmission investments?
- How is the need for new transmission investments evaluated?
- Who makes the necessary investments?

3.1 Who Should Evaluate Need for Transmission Investments?

Two major alternatives exist; these are dependent on whether there is an independent system operator, an independent system administrator, and whether the ownership of transmission is more than functionally separated from generation assets. Generally, long-term transmission planning should rest either with the transmission owner or with an independent system operator. Interconnection requirements, while subject to regulatory approval, should be managed by the transmission owner.

The advantages of assigning responsibility for long-term transmission planning to an independent system operator stem from the independence of choices made by this body. This would be especially important when ownership of transmission is not separated from ownership of the generation that provides bundled or standard offer service. With this ownership structure and without independent transmission planning, it could be possible for the transmission owner to favour affiliated generation in its transmission planning decisions, especially if generation additions begin to create congestion. Disadvantages include the need to create and staff the organization to perform these functions, redundancy with capabilities that would still be needed by the transmission owner, lack of personnel with detailed experience with the system, etc.

The advantages of keeping long-term transmission planning responsibility with the transmission owner include ease and speed of implementation as well as the presence of needed personnel. Where ownership of the transmission and generation remains aggregated, keeping planning responsibility with the owner would require regulatory oversight to assure that favoring of affiliated

generation did not occur. Less aggressive regulatory oversight would be needed where transmission and generation ownership was separated and the transmission owner received no direct or indirect gain from the competitive advantage attained by generation.

3.2 How is the Need for New Transmission Investments Evaluated?

Traditionally, vertically integrated utilities planned their transmission systems to meet reliability requirements and ensure that the outputs from generation could be transported to customers. Utilities sometimes built transmission lines for economic reasons; for example, to provide access to cheaper power or to export surplus power. Today, transmission systems are called on to serve dynamic and rapidly expanding markets with increasing inter-jurisdictional power flows. This suggests a need for expanding the set of transmission planning criteria to accommodate the requirements of increased inter-jurisdictional trade. A market-focused approach to transmission planning might seek to reduce the number of times transmission-service requests are denied and generation must be redispatched to avoid congestion.

3.3 Who Makes the Necessary Investments?

If NSPI maintains both ownership and control of transmission system assets (*i.e.*, there is no independent system operator), it would also likely retain responsibility for transmission planning and expansion. But if the system operator and transmission owner are two separate entities, there will be a need for some form of competitive solicitation process for arranging new transmission investments. With an independent system operator, there may be situations where the transmission owner is unwilling to make transmission investments that are proposed by the system operator, *e.g.*, the transmission system owner might determine that the proposed facilities are not going to generate sufficient revenues to warrant the investment or require rate increases that are not in customers' best interests. Under these conditions the system operator would likely have to contract out the construction of these facilities. In several jurisdictions, the system operator coordinates a transmission planning process involving both transmission owners and market participants. Transmission system investments are then made in accordance with the plan formulated by the system operator. The *Regional Transmission Expansion Plan* of the PJM Interconnection is an example of this process.